Distributed Generation White Paper

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Introduction

State utility and energy commissions need to develop a process where the incentives reflect the value of distributed generation (DG) to individual customers and the utility as a whole. Achieving this balance will result in DG potentially saving money, improving reliability, better meeting customers' needs, and improving the environment.

Governors, legislators, environmental regulators and consumers are relying on state utility and energy commissions to resolve conflicting claims of DG developers, environmentalists and utilities regarding the connection of DG to electric systems. Utilities[1] are concerned about cost recovery in the face of increased DG use; public policies need to balance short-term cost recovery issues with the potential long-term benefits of DG. Decisions must be made that address concerns without stifling a potential new solution to meet future energy needs.

State utility commissions need to know about DG technologies, their economics, and their impacts to address these issues. Can DG really help Indiana meet these challenges? What are the opportunities for DG in Indiana? Can DG help with reliability? What is likely to happen? How soon? How will DG impact consumer electric costs? How will DG impact existing rate structures? How will this play out in Indiana? Above all, how will policy alternatives affect diverse and sometimes conflicting constituent concerns?

This paper[2] is intended to provide an overview of policy decisions that need to be examined before the implementation of a DG policy. We will examine six specific DG issues that have a high impact on how to create a competitive environment for DG. They also have a direct impact on more general regulatory objectives. These issues are:

1. Interconnection Standards
2. Siting and Permitting
3. Net Metering
4. Stranded Costs
5. Standby Rates
6. Buy-Back Rates

Although it is tempting to simplify the policy making process by considering the issues separately the impacts of policies tend to be additive and interrelated in nature.

Definition of DG and an Overview of Issues

Distributed generation is generally defined as an energy production system that is physically close to the load. It does not necessarily require the use of the utility system to deliver the electricity to the consumer's meter, although it may inject energy into the

[1] Reference made to certain parties, like 'utilities' are meant to be representation of a general term and/ or observations of these parties in other states.

[2] Source: "Distributed Generation: Policy Framework for Regulators", An Arthur D. Little White Paper, 1999.

utility system, or the customer may choose to maintain an interconnection for supplemental and backup power. Distributed generation may consist of large, gas-fired power plants dedicated entirely to one industrial customer, small gas turbines that power a fast food restaurant, a methane recovery unit at a waste dump, or a residential fuel cell. The distinguishing feature is not whether these devices generate power with fossil fuels or environmentally friendly technologies, but that they are dispersed across the utility's electric network rather than concentrated in a distant location and connected to the load center with transmission lines. Finally, these technologies are usually small enough to add in increments that better match the rate of load growth characteristic of today's industry.

Industrial electric consumers may find self-generation of their electric requirements increasingly attractive as technological developments continue to improve unit performance and decrease unit costs. Service quality improvement, especially with regard to reliability, is often associated with distributed generation. Service quality improvement also refers to the quality of the power being supplied. Some modern industrial processes and equipment can be seriously compromised by even a small power surge or drop in frequency. DG units can ensure that a constant, high quality of power is delivered to the customer. These same technological developments, decreasing costs and improved electric service quality will make DG a viable alternative for many smaller commercial customers, and quite possibly, residential customers.

The debate about DG centers on interconnection standards for physical connection to the utility grid and appropriate financial incentives so that individual customers take actions that benefit or at least don't harm others. The key is the design of sound rate structures that reflect economic efficiency and other policy objectives that the IURC develops. Therefore, the Commission wants to discuss all six issues and use the results for a DG rulemaking that will balance the concerns and the possible benefits.

1. Interconnection Standards

Interconnection standards for physical connection of general DG technologies to the grid have been in development by an IEEE (Institute of Electrical and Electronics Engineers) committee for over two years. An IEEE article[3] stated, "The biggest roadblock DG faces is that every state and utility has different technical interconnection requirements. Simplifying these requirements would help minimize engineering and design costs, streamline the installation and operation of distributed systems and increase safety by promoting the use of simpler, more reliable, protective relaying systems…The IEEE standard will contain requirements for performance, operation, testing, safety and maintenance of interconnections between distributed resources and other electric power systems." The U.S. Department of Energy (DOE) funded IEEE to develop the standard on an accelerated schedule of two to three years—about half of the time period usually

[3] "IEEE Draft Standard Helps Solve Interconnection Problems," Kathy Kowalenko, The Institute, Feature Article, May 2001, http://www.spectrum.ieee.org/INST/may2001/fdistrib.html

required. The IEEE Standards Association Board voted to undertake the standards in March of 1999.

The proposed rule is known as IEEE SCC21 P1547, "Distributed Resources and Electric Power Systems Interconnection". The IEEE approval process involves writing drafts of the proposed rule and then putting the draft rule to a vote. The rule must have 75% Yes votes to be approved. The P1547 rule has gone to ballot eight times. Draft 8 received 96% returns, with 66% affirmatives. The IEEE committee continues to work on the rule, and the Chair of the committee stated that the rule will only go to another ballot after members have thoroughly discussed among themselves their stated suggested remedies and have a positive sense that the future reworded draft would be satisfactory to achieve affirmative ballot status.

State Activity: At least five states (California, Delaware, New York, Ohio, and Texas) have developed technical and contractual interconnection rules for all customer-owned DG technologies. These rulemakings generally took a fair amount of time (one to two years) with high manpower demands placed on state commission staffs as well as interested parties. Once the IEEE standards are implemented, it is anticipated that many, if not all, of the state interconnection rules will be superseded by the IEEE standards. The IURC assumes that these standards will be finalized at the same time as we are working on the other DG issues. However, if there are issues with the IEEE standards that we can address in our rulemaking they should be highlighted now.

Solar Standards: In January 2000, the IEEE Standards Board approved a standard for interconnecting photovoltaic (PV) systems under 10 kW to the utility grid. The new standard, entitled Recommended Practice for Utility Interface of Photovoltaic Systems is referred to as IEEE Standard 929-2000. Both Indianapolis Power and Light Company (IPL) and PSI Energy, Inc (PSI) employ these standards in net metering tariffs that have been approved through the Commission's thirty-day filing process.

FERC Generation Interconnection Rulemaking: On October 25, 2001, the FERC issued an Advanced Notice of Proposed Rulemaking (ANOPR) on Standardized Generation Interconnection Agreements and Procedures. The original deadline for filing comments of December 21, 2001, has been extended to January 25, 2002.

A broad-based group, known as the Generator Interconnection Coalition, has filed a status report on its consensus process, an interim draft standard connection agreement and an interim draft standard interconnection procedures document. The Coalition includes representatives from generators, marketers, transmission owners, industrial power producers, transmission dependent utilities, regional transmission organizations, independent system operators, distributed resources and state commissions. FERC asked the Coalition to file a single consensus document on January 11, 2002 to allow all stakeholders in the ANOPR process to have the opportunity to seek clarification and comment orally on the draft documents during plenary meetings. The public meetings were held on January 17 and 18, 2002, at FERC.

This FERC activity will result in interconnection standards for generators that wish to connect to the transmission system and sell electricity on the wholesale market. The standards thus will entail how these generators will connect to the transmission system, and who will pay for what share of the costs. These FERC standards thus do not encroach upon or overlap the IEEE standards discussed above, nor do they mitigate any need for individual states to address DG standards for those customers who wish to install equipment and interconnect to the distribution system of their local utility.

2. Siting and Permitting

The debate on siting and permitting requirements is mainly focused on opportunities to reduce the time and costs associated with siting and permitting DG and still protect–and perhaps even strengthen–the environment, public health and safety, and other social priorities. As pressures grow for access to increasingly efficient and environmentally friendly power, regulators and legislators are beginning to evaluate options to restructure environmental and siting requirements to remove potentially unproductive barriers to DG.

While many DG facilities are too small to trigger most states' power generation facility siting requirements, which were established for central plants, they may well be required to comply with local, state, and regional permitting requirements, as well as building and fire codes. Issues typically relate to location-specific concerns. The main focus is air emissions, but other local sensitivities may include factors such as noise, aesthetics, land use, and risk communication. Local requirements may dictate an additional set of proceedings for issues related to the use of natural gas. Overall, there may be several applicable (and potentially overlapping) permits, codes, and requirements for a DG project, each with its own separate process, constituency and decision makers.

Of these various permitting considerations, many DG supporters believe that several interrelated air-permitting issues in particular deserve the serious attention of legislators and environmental regulators. The structures of the permitting processes themselves often appear ill suited to the concept of smaller, decentralized power generation facilities. Current time requirements (typically 6 to 18 months), codes, and emission standards are usually not standardized, but rather are developed on a project-specific basis. As a result, even though a DG project may be able to satisfy regulatory requirements, the time-consuming and expensive processes needed to demonstrate compliance could render the project economically unfeasible. The environmental regulators, on the other hand, are concerned that the review process be consistent and ensure that all concerns can be addressed as completely as necessary. Those skeptical of potential permitting reforms maintain that a streamlined process designed to accommodate project timetables and economics might, at least in some cases, sacrifice the quality of review designed to protect the public interest.

DG proponents are urging the development of uniform, efficient permitting requirements and processes, particularly for environmental and safety concerns, that balance DG project economics and public policy objectives. One element of a revised approach is precertification, a practice already used for automobiles and a wide variety of other commercial and industrial products. Nationally recognized, independent (or government) testing laboratories would conduct initial testing and characterization of the emissions from DG products, and then recommend minimum requirements for DG technology emissions that local, state, and/or regional air pollution control agencies could then consider, possibly modify, and adopt. The laboratories would then test DG products and pre-certify that they meet those minimum regulatory requirements. This has the advantage of creating a streamlined and consistent process while allowing localities to retain their permit jurisdiction.

This issue primarily affects policy objectives related to competition (both generally and for DG) and economic efficiency, and protection of the environment. Permitting and siting requirements have an impact on the objective of competition and economic efficiency to the extent that they may affect DG market adoption. These requirements also work directly to support environmental protection objectives.

The influence that permitting and siting requirements have on a competitive environment for DG ranges from Neutral to DG Disadvantaged. If a jurisdiction's permitting and siting requirements for DG projects were not modified to both protect the public interest and reasonably reflect timing and budget considerations critical to DG project success, then the competitive environment for DG would be constrained. If, on the other hand, these permitting processes were modified in a balanced manner, then the issue would have a neutral impact on the overall competitive market environment for DG. Under these conditions, public concerns would be effectively protected in such a way that the process itself neither favored nor hindered DG against other competitors. Debate on appropriate permitting and siting process design is not unique to DG. Initiatives to refine the timing, requirements, and procedures for the approval of various types of projects, including energy facilities, are common on the local, state, and federal levels of government.

Regulated variables when siting a power plant of any size include air quality, fuel supply, noise and safety. These same issues affect each DG installation. However, government policies that specifically deal with DG, as a choice for meeting energy needs are limited in most states. Communities have not made DG an integral part of their long-range energy infrastructure plans. A lack of DG technical performance data and no precertification process for equipment slows regulatory reviews. Taken together, these factors create an uncertain climate for DG when it is proposed as a development.

3. Net Metering

Net metering is an arrangement where small customers can offset their electricity consumption and sell any extra energy generated to the interconnected utility. A bi-directional meter registers electrical flow in both directions. This type of metering enables a monetary exchange based on net customer generation and consumption.

Net Metering is the starting point of any rulemaking involving DG. Unless a customer exits the grid entirely, he is going to want to get some type of credit for generating some portion of his electricity demand. In a simple world in which a customer were to offset some but not all of their monthly energy use, their meter would simply not turn as much and they would receive a lower bill from their utility. This is how the IPL and PSI PV tariffs work.

More issues with net metering arise when the possibility of the customer generating more electricity than they use is considered. How should the excess power be valued? Unless somehow technically prevented, the excess power would flow back onto the grid, providing a benefit to the utility. This concept is embodied in the term buy-back rate, which we devote a separate section to.

As an example, Wisconsin has a net metering rule that applies simple net metering for all customer-owned generation of 20 kW or less. If the customer is a net purchaser, it is billed at the energy rate for its class of customer. If the customer is a net seller, it is paid one of two buy back rates based on the fuel source. For renewable resource generators, the buy back rate is the customer's retail rate. For nonrenewable resource generators, the buy back rate is the utility's avoided cost rate. This policy thus encourages the installation of renewable resource generators, because the retail rate is greater than the utility's avoided cost.

There are potential problems involving how power sold back to the utility is valued. Therefore, net metering can be a useful method for small numbers of participating customers, but potential problems are exacerbated by a large number of participants. One potential problem is that the energy portion to the tariff, which is a popular method to value the power sold back the utility, may contain fixed charges and costs. Thus, such a buy-back rate would overcompensate the customer for the energy sold back to the utility, and in turn hurt the utility's other, non-participating customers. A second potential problem is that the energy rate is an average rate over the whole year, and so it may not correctly value the energy. For example, on a hot summer day when power supplies are tight, customer-generated energy has more value to the utility than the flat average value. Alternatively, on a fall night the customer-generated energy will probably have less value to the utility than is shown by the flat average rate.

These potential tariff problems exist even when the customer is simply reducing consumption by operating their own generation equipment, since the reduction of energy is implicitly valued at the energy rate of their utility's tariff.

4. Stranded Costs

The stranded cost debate centers around whether an operator/user of DG should be forced to compensate the utility for stranded investment costs. Utilities in other states examining this issue have contended that the loss of customers on a large scale and the associated revenues will result in stranded investment costs, and the remaining customers will have to bear the costs of these unused or underutilized distribution system facilities. Consumer representatives might argue that the bulk of a utility's T&D system has likely been paid for, and that ongoing maintenance expense is covered by fixed charges in the tariffs. Thus, if a customer simply reduces load, he or she will still be paying the fixed charges. And if the customer leaves the system entirely, it is not likely to significantly affect the utility's revenues. The recovery of these costs will likely have to be a balancing act between the rights and responsibilities of stakeholders with competing interests.

Utilities may argue that if operators/users of DG do not compensate them for their stranded costs, either the company's shareholders or non-DG customers will ultimately have to bear the burden. The utilities could point out that they made investments in generation, transmission, and distribution with the assumption that they would receive a fair return on those investments. They may, therefore, propose the use of exit fees and other charges to recoup the stranded investments made on behalf of a customer.

One method of stranded cost compensation would be a form of a competitive transition charge (CTC). CTCs have been used in many states during restructuring to pay for stranded generation assets that are no longer economic in an open power market. CTCs would likely only exist for a limited period of time, and so would probably not affect the long-range success of DG.

Exit fees, on the other hand, could be a disincentive to the development of DG. An exit fee is another form of stranded cost recovery that a utility collects when a customer decides to leave the grid or reduce its load through DG. This charge is intended to compensate the utility for investments it has made in its systems on behalf of that customer.

Proponents of DG suggest that no stranded costs will result, as the amount of DG installed is not likely to outpace demand growth. Instead, the potentially underutilized assets would end up being used to meet new loads caused by the growth in demand. Another argument is that the types of fees and charges utilities may propose to levy will discourage the adoption of innovative energy solutions like DG, and will result in limitation on competition from different and sometimes more efficient sources.

5. Standby Charges

Standby rates are utility rates that a customer pays to receive power from the grid at times when its own DG is unavailable. The cost of standby delivery strongly affects the economic viability of the DG technology in instances when the customer cannot or chooses not to disconnect from the grid. Because disconnection from the grid requires that a customer maintains its own backup power source and follow its own load precisely, most customers are likely to find grid attachment to be the more attractive option. Thus, standby rates have become a significant point of discussion in the DG debate.

It is generally agreed that standby rates should reflect the cost to the utility of providing standby service, thereby allowing a customer to make an economically efficient choice between alternative forms of electrical generation. However, determining a cost-based rate has proven difficult. Data regarding the impact that standby customers have had on utility systems has been inadequate, and opinions on the best application of that data have differed widely.

Most of a utility's cost for providing standby service is associated with the fixed cost of the T&D system. Customers purchasing standby service pay a tariff that is usually in the form of a monthly demand ($/kW) charge. If the standby charge associated with DG is below the actual cost of providing this service, the cost will tend to be shifted to other customers. Alternatively, overstating standby costs might discourage DG that might otherwise be attractive. Depending on the circumstances, overstatement of standby charges might also encourage a customer to abandon the grid altogether. The issue of balance and fairness can be complicated by the fact that the actual cost to provide this service may vary considerably from customer to customer.

As with utility rates in general, a standby delivery rate may be volumetrically priced, or may include a high fixed charge and low per kWh charge. Utilities argue that standby rates, even more so than basic rates, should include a high fixed charge. The customer is reserving the ability to deliver a certain generation amount over the T&D system, but will use that system for a short period of time. The T&D system must be built and maintained to accommodate the customer’s maximum load, so the utility must charge a rate based on the customer’s maximum load requirement if it is to recover its costs.

DG proponents support development of lower-priced standby rate choices that are more responsive to the needs of individual customers. Many utilities do not offer the customer any choice in the level of reliability or the amount (kW) of standby service that they receive. For example, if a facility with a 400 kW peak demand installs a 300 kW generator, current industry practice would be for the utility to charge the customer for 300 kW of standby service. A more flexible approach might be for the owner to be able to choose to rely on the utility for 100 kW of backup power and perform load shedding for the other 200 kW when the 300 kW DG unit is unavailable. This would provide better price signals to customers by lowering initial barriers and, equally important, would reward DG technologies for reliability. This approach also links prices more closely to the actual value of the service to the customer.

It is a straightforward enough process to calculate rates that reflect the probability of a self-generating customer contributing to system peak needs (i.e. causing costs), in much the same way that rates for interruptible service are determined. Such rates can be differentiated by time of use, on either an energy or capacity basis.

Many utilities agree that current standby rates are unfair and should be based on the cost of service. However, they contend that current standby charges are too low and do not fairly recover the full cost for providing this service. Often standby rates only cover the cost of T&D facilities and not other costs the utility can incur when providing this service (e.g., procuring back-up power for customers on spot markets). Some utilities also charge that customers in certain rate classes that have volumetric rates (e.g., small commercial and residential customers) are not paying the full costs of standby services provided to them when they install DG. These current artificially low rates can cause cost shifting and send inappropriate price signals to customers, causing them to reach economically inefficient decisions.

Utilities advise that when modifying the current rate structure to accurately reflect standby costs, regulators will have to study the physical limitations of the T&D system as well as gain a better understanding of the reliability performance of DG technologies. Flexibility in standby rate design is limited in that each customer has a dedicated portion of the T&D system that was installed solely for that customer and cannot be redeployed when the customer is not using the system. The cost of that portion of the system does not change regardless of the level of reliability the customer desires or the frequency of use by the customer. Utilities maintain that the cost of the portion of the system that a customer shares with other customers is dependent on the level of system reliability that is already reflected in their rates. Moreover, actual standby service costs are dependent on a complicated mix of factors that affect reliability, including the DG customers' locations in the system, the reliability of the DG technology in general, and the quality and maintenance of each particular installation.

This issue essentially affects the same policy objectives as those for stranded costs, including competition (both generally and for DG) and economic efficiency, protection of consumers from inappropriate cost shifting, maintaining a viable utility franchise, and safety and grid reliability. Competition and economic efficiency, as well as safety and grid reliability, are potentially affected to the extent that standby charge policy influences the market adoption of DG. The question of whether DG installations compensate utilities for these standby services -- and if so, whether it is done in an equitable manner -- may determine whether cost shifting occurs within the customer base. It also affects decisions on the appropriate level of investment required to provide these services, which in turn could influence the viability of the utility. It should be noted that if utilities are allowed to charge standby rates that are not "balanced," but rather impose excessive costs on DG owners, DG could be disadvantaged. This is particularly important since this policy issue is rated as having a high impact on the DG competitive environment.

6. Buy-Back Rates

Buy-back rates may not be an issue for the smaller DG units installed by a residential user because they won’t often, if ever, have excess power to sell back to the utility. However, some on-site DG projects will have excess capacity, which could benefit the grid if available at time of capacity shortages. In Indiana, the only market for this power is the connecting utility, thus that utility’s buy-back rate is the only option available to a customer with excess capacity.

Buy-back rates could play a role in encouraging DG installation, however, utilities with adequate generation or those with an interest in maintaining their customer base have little incentive to facilitate the interconnection of DG. In Indiana, the typical avoided cost rate of 1-2¢/kWh is based on PURPA[4] rules, and it is questionable whether these costs adequately reflect the avoided cost to the utility in today's competitive wholesale market. A successful buy-back rate would have to be set up so that it recognizes the value of DG in meeting system capacity shortfalls.

A variation on that theme would be a preferential rate for DG projects that are sited where they are able to supplement central station generating plants and the distribution grid. By adopting this type of tariff, the rate a DG owner would receive for contributing electricity to the grid would depend on the actual system conditions for electricity at the time of contribution. Under real-time pricing, DG owners would have an incentive to increase generation for grid support during these periods because the buy-back rate would exceed the cost of operation.

Other possibilities in designing buy-back rates would be to define small-scale and high efficiency, and to distinguish between DG used for system support and DG used to meet environmental regulations or to encourage specific technologies. Another option would be to vary the buy-back rate depending on whether the generation is dispatched by the utility or the unit's owner, with utility-dispatched equipment receiving a higher rate.

The following are just some examples of potential buy-back rate options.

?? In Wisconsin as previously noted, net metering is used for all customer-owned generation of 20 kW or less. If the customer is a net purchaser, it will be billed at the energy rate for its class of customer. If the customer is a net seller, it is paid one of two buy-back prices based on the fuel source.
?? Under real-time pricing, the rate a DG owner would receive for contributing electricity to the grid would depend on the actual demand at the time of contribution.
?? Generation that meets the definitions of high-efficiency and small-scale and that provides benefits in the form of environmental performance or that employs specified technologies, could qualify for buy-back rates equal to the greater of the customer's energy rate or a rate negotiated between the utility and the customer. DG that is produced from environmentally friendly resources or developing technologies can also be strategically sited to support the electric distribution system.
?? The Regulatory Assistance Project recommends including in the buy-back rate, a credit for the 'de-averaged' distribution price for that location (depending on the need on that particular distribution system at any given time). The utility could establish financial credits for DG installed in certain locations, the amount of which would be a function of the distribution cost savings generated.

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[4] Public Utility Regulatory Policies Act of 1978. Codified in general at 16 U.S.C. et seq. Further codified in 170 IAC 4-4.1 et seq.

7. Questions

Please address any and all issues related to Distributed Resources including but not limited by the following questions:

a. Please provide a definition of distributed generation, including engineering characteristics and unit size. Should the definition differ depending on the customer class?

b. Assuming net metering as the first step in a DG rulemaking, what are the benefits for customers with net metering and what are the possible negative effects?
c. What kind of tariff structure can be used to deal with different amounts and sizes of DG and still make net metering practical?
d. How should a utility determine the fixed amount of cost per customer with net metering, for both a net buyer and/or net seller?
e. How do tariffs need to be designed to adequately reflect the efficient recovery of the fixed and variable costs for service to customers that operate DG equipment using a net meter?

f. How can stranded costs be identified and measured?
g. What, if any, are the benefits and revenues that should be considered as offsets to stranded costs?
h. What rate design alternatives would reduce the potential for any stranded costs?

i. Should standby rates for backup power be used, and if so under what criteria?
j. What different kinds of standby services do customers with DG require and can the utility reasonably supply?
k. In order to determine the necessity and proper design of standby rates we need further information on distribution system design, operations, and cost structure. Please provide any information that might help to develop efficient standby rates.
l. Are there areas in Indiana with distribution constraints?
m. Should utilities be required to file a location-specific set of T&D costs?

n. What constitutes an economically efficient buy-back rate?
o. What information should be included in a utility standard application form for distributed generation?
p. What costs are incurred by a utility to review a DG project?
q. Do these costs vary for different DG project proposals?
r. How long should it take a utility to evaluate a project?
s. What are the criteria a utility should use to evaluate a DG project?